

RECEIVED  
DEC 22 2021

OMB No. 2040-0042 Approval Expires 4/30/2022

United States Environmental Protection Agency			For Official Use Only	
<b>Underground Injection Control</b> <b>Permit Application for a Class I Well</b> (Collected under the authority of the Safe Drinking Water Act. Sections 1421, 1422, and 40 CFR Part 144)			Date Received	
			Permit Number	
<b>Read Attached Instructions Before Starting</b>				
I. Owner Name, Address, Phone Number and/or Email			II. Operator Name, Address, Phone Number and/or Email	
Alan Harrison 1675 Broadway Suite 2800 Denver, CO 80202 303-825-4822 aharrison@kpk.com			K.P. Kauffman Company Inc. 1675 Broadway Suite 2800 Denver, CO 80202 303-825-4822	
III. Commercial Facility	IV. Ownership	V. Permit Action Requested		VII. Indian Country
<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No	<input checked="" type="checkbox"/> Private <input type="checkbox"/> Federal <input type="checkbox"/> State/Tribal/ Municipal	<input type="checkbox"/> New Permit <input type="checkbox"/> Permit Renewal <input checked="" type="checkbox"/> Modification <input type="checkbox"/> Add Well to Area Permit <input type="checkbox"/> Other		<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No
VIII. Type of Permit (For multiple wells, use additional page(s) to provide the information requested for each additional well)				
<input checked="" type="checkbox"/> A. Individual <input type="checkbox"/> B. Area	Number of Wells 1	Well Field and/or Project Names Spindle		
IX. Class and Type of Well (see reverse)				
A. Class I	B. Type (enter code(s)) I	C. If type code is "X," explain.		
X. Well Status		XI. Well Information		
<input checked="" type="checkbox"/> A. Operating Date Injection Started		API Number 05-123-14291		
<input type="checkbox"/> B. Conversion Date Well Constructed		Permit (or EPA ID) Number CO10938-02115		
<input type="checkbox"/> C. Proposed		Full Well Name Suckla Farms INJ Well (EPA) #1		
XII. Location of Well or, for Multiple Wells, Approximate Center of Field or Project				
Locate well in two directions from nearest lines of quarter section and drilling unit			Latitude 40.066810	
Surface Location SE 1/4 of NW 1/4 of Section 10 Township 1N Range 67W			Longitude -104.879100	
500 ft. from (N/S) S Line of quarter section				
2020 ft. from (E/W) W Line of quarter section.				
XIII. Attachments				
In addition to this form, complete Attachments A-U (as appropriate for the specific well class) on separate sheets. Submit complete information, as required in the instructions and list all attachments, maps or other figures, by the applicable letter.				
XIV. Certification				
I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR § 144.32)				
Name and Official Title (Please Type or Print) Alan Harrison - VP of Exploration and Production		Signature 		Date Signed 12/02/2021

## **Form 7520-6 Attachment A**

### **Part I: Well Location**

The well location is SENW, 500 ft FSL, 2020 ft FWL, section 10, Township 1N, Range 67W, Weld County, Colorado

### **Part II: Area of Review Size Determination**

Because this well does not inject hazardous waste, the size of the Area of Review is a 1/4 mile radius from the wellbore.

### **Part III: Map of Area of Review**

The maps and tables on the following pages show the water wells and the oil/gas wells that are within the 1/4 mile radius of the Suckla Farms #1

# Water Wells within 1/4 Mile of Wattenberg Disposal

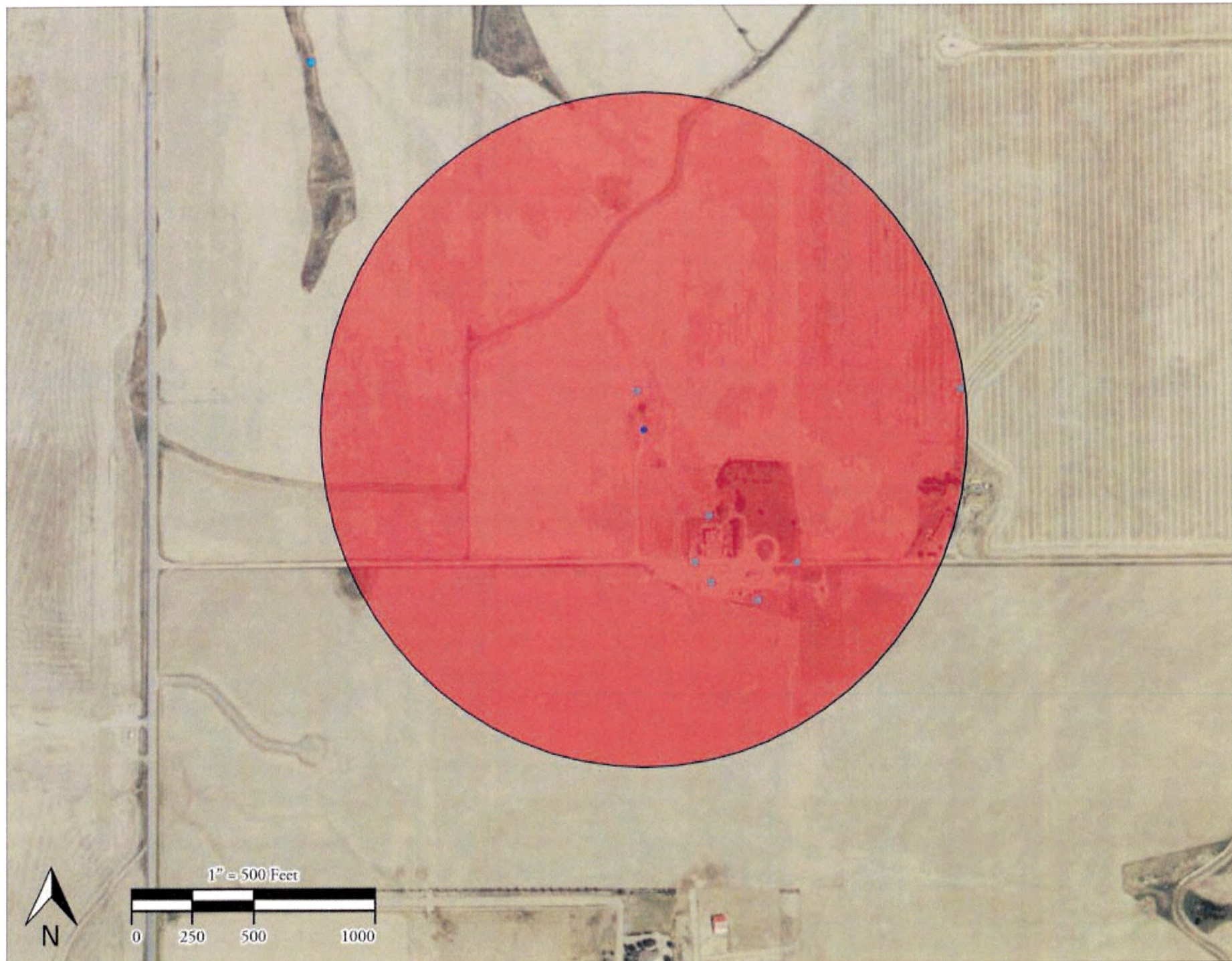
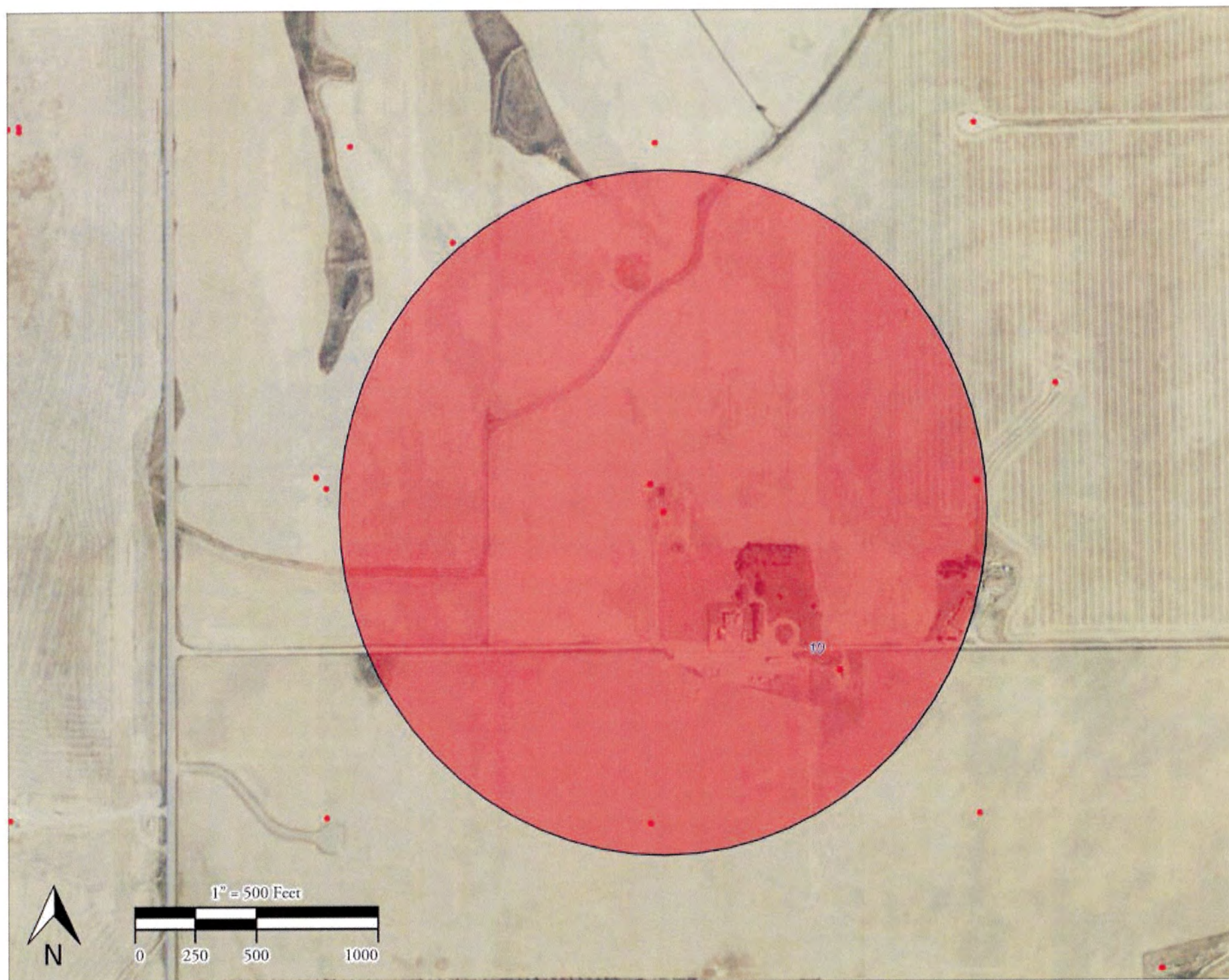


Table #1: Water Wells within 1/4 Mile of Wattenberg Disposal									
Receipt	Permit	Qtr Qtr	Section	TWSHP	RNG	Depth	Top Perf	Bottom Perf	Aquifer
		NESW	10	1.0 N	67.0 W	0			ALL UNNAMED AQUIFERS
39799	39799- MH	NESW	10	1.0 N	67.0 W	0			ALL UNNAMED AQUIFERS
3642319	281522-	NWSE	10	1.0 N	67.0 W	24	14	24	ALL UNNAMED AQUIFERS
0047236A	47236- MH	NWSE	10	1.0 N	67.0 W	0			ALL UNNAMED AQUIFERS
48618	48618- MH	NWSE	10	1.0 N	67.0 W	24	14	24	ALL UNNAMED AQUIFERS
59627	59627- MH	SWNE	10	1.0 N	67.0 W	0			QUATERNARY ALLUVIUM
3624584	66819- F	SWNE	10	1.0 N	67.0 W	803	480	788	LARAMIE FOX HILLS
52282	52282- MH	SWNE	10	1.0 N	67.0 W	24	9	14	ALL UNNAMED AQUIFERS
62156	62156- MH	SWNE	10	1.0 N	67.0 W	0			
3664286	294033-	SWNE	10	1.0 N	67.0 W	24	9	14	ALL UNNAMED AQUIFERS
62499	62499- MH	SWNE	10	1.0 N	67.0 W	0			

# Oil and Gas Wells within 1/4 Mile of Wattenberg Disposal



**Table #2: Oil and Gas Wells within 1/4 Mile of Wattenberg Disposal**

API	Status	Well	Qtr Qtr	Section	TWSHP	RNG	Formation	Top	Bottom	TD
05-123-07426	PA	SUCKLA BROWN UNIT *6	NESW	10	1N	67W	SUSX	4775	4826	4910
05-123-08069	PA	SUCKLA BROWN UNIT *9	SENE	10	1N	67W	SUSX	4746	4774	4919
05-123-09485	SI	SUCKLA- BROWN UNIT *17	NWSE	10	1N	67W	SUSX	4824	4850	5074
05-123-07481	PA	SUCKLA BROWN UNIT *4	SWNE	10	1N	67W	SUSX	4796	4840	4945

#### **Part IV: Area of Review Wells and Corrective Action Plans**

There are no wells within the  $\frac{1}{4}$  mile area of review which penetrates the Lyons formation, so there is no need for a corrective action plan.

The applicant identified one hundred forty (140) oil and gas wells which are located within a one (1) mile radius of the Suckla Farms #1 well. These oil and gas wells range in total depth from 4783 ft to 8515 ft. None of the oil and gas wells penetrate the upper confining zones nor do they penetrate the injection zone.

There are eighty-four (84) water wells that are located within a one mile radius of the Suckla Farms #1 well. These water wells extend from a depth of 10 ft to 840 ft. None of the water wells penetrate the upper confining zones or the injection zone. There are several hundreds of feet of confinement (tight geology) which exists between the lowermost water well and the injection zone.

#### **Part V: Landowner Information**

- Columbine Jersey Farms Inc.: 80 Mistletoe Rd. Golden, CO 804019623
- Suckla Farms Inc.: 4468 County Road 19 Fort Lupton, CO 806218405
- 4 Z Investments LLP: 9075 County Road 10 Fort Lupton, CO 806218447

**Form 7520-6 Attachment B**

**Part I: Geological Data**

**Table #1: Geological Setting**

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS mg/l	ZONE TYPE
Arapahoe	Sandstone, siltstone, and shale	350		< 10,000 mg/l	USDW
Laramie	Sandstone, mudstone, clay and coal	unknown		< 10,000 mg/l	USDW
Fox Hills	Sandstone, siltstone and shale	650		< 10,000 mg/l	USDW
Pierre Shale	Shale	700			Major confining zone
Niobrara Shale	Shale	7362			Confining zone
Codell	Silty, shaley and fine-grained sandstone	7694		unknown	Geological Setting
J Sand	Sandstone, Siltstones and shale	8133		unknown	Geological Setting
Dakota Sandstone	Sandstone and shale	8281		unknown	Geological Setting
Lakota Sandstone	Sandstone	8368		unknown	Geological Setting
Morrison	Mudstone, sandstone, siltstone, and limestone	8404			Confining zone
Entrada	Sandstone	8562		unknown	Geological Setting
Harriman Shale (Forell)	Shale	9069	9139		Confining zone
Blaine Salt	Anhydrite and Shale	9143	9274		Confining Zone
Lyons Sandstone	Sandstone	9274	9422	33,000 mg/l	Injection zone
Santanka Shale	Shale	9422			Confining zone

The Suckla Farms #1 Class I disposal well is located about 25 miles North of Denver, Colorado in the Denver-Julesburg Basin. The Denver-Julesburg Basin is a north-south trending "trough" or asymmetrical syncline. Strata which are exposed along the Front Range dip steeply eastward. On the East flank of the Basin, the strata dip gently westward. The well is located approximately 5 to 10 miles east of the axis of the Basin where the thickness of the sedimentary section is near its maximum. Formation top depths listed above were obtained from the Well Completion Report for the Suckla Farms # 1 well dated July 13, 1989 and page 4 of the permit application. Additional geological data was obtained from the permittee regarding the depths of the Blaine Salt and Lyons Sandstone formations. The designation of USDWs and non-USDWs data has

been obtained from page 4 of the application and from the 2003 Statement of Basis for the Final Renewal Permit issued for the Suckla Farms #1 well.

**Table #2: Injection Zone Data**

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity
Lyons Sandstone	9274	9422	33,000	0.8415	0.06

The targeted portion of the Lyon injection zone is the sandstone unit encountered at about 9276 ft. The Lyons Sandstone is a massive cross bedded sandstone with fine to coarse grains with some cementing. The perforated interval of the Lyons is from 9276ft to 9418ft. The injection zone is expanded to depths between 9274 ft to 9422ft. to accommodate depths within the Lyons Sandstone that are perforated and sandstones which may store fluid. The depths were determined by the permittee. As indicated above, the disposal of oil field related fluids and non-hazardous fluids will be into the Lyons Sandstone. The Suckla Farms #I was sampled and analyzed prior to conversion to a Class I injection well and reservoir fluid contained about 33, 000 mg/liter total dissolved solids (TDS). Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

**Table #3: Confining Zone Data**

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS, mg/l	ZONE TYPE
Blaine Salt	Anhydrite and shale	9143	9274	N/A	Upper Confining zone
Santanka Shale	Shale	9422		N/A	Lower Confining zone

The upper confining zone is the Blaine Salt and is encountered at 9143 ft. The Santanka Shale serves as the lower confining zone and is encountered at a depth of 9422 ft.

**Table #3: Underground Sources of Drinking Water**

FORMATION NAME	GEOLOGICAL DESCRIPTION	TOP DEPTH, ft	BOTTOM DEPTH, ft	TDS mg/l	ZONE TYPE
Arapahoe	Sandstone, siltstone, and shale	350		<10,000 mg/l	USDW
Laramie	Sandstone, mudstone, clay and coal			<10,000 mg/l	USDW
Fox Hills	Sandstone, siltstone and shale	650		<10,000 mg/l	USDW

In this area, the principal aquifers used for public and domestic and other uses are the Arapahoe Formation and the Laramie-Fox Hills aquifer system. These major USDWs overlie the Pierre Shale, which is a major confining unit in the basin, and is approximately 6600 feet thick. The Pierre is principally 6600 feet thick. The Pierre is principally a dark gray marine shale, but sand lenses, such as the Hygiene sand and the Wellington sand do occur in places. The Hygiene and the Wellington sands often contain water with a quality and quantity sufficient to be defined as a USDW. All the formations underlying the Pierre are not USDWs because they contain water with a TDS of greater than 10,000 mg/liter. The injected interval, prior to injection, contained water with a TDS of approximately 33,000 mg/liter.

**Image #1: DJ Basin Stratigraphy Column**

System/ Series	Stratigraphic unit		Storage Assessment Unit (SAU) notes
	North and Western Denver Basin	Eastern Denver Basin and adjacent areas	
Tertiary	Denver Formation	Dawson-Denver Formations	
Upper Cretaceous	Arapahoe Formation	Arapahoe Formation	<b>Terry and Hygiene Sandstone Members SAU</b> C50390105 Seal: Pierre Shale Reservoir: Sharon Springs Member and Hygiene "Shannon" and Terry "Sussex" Sandstone Members
	Laramie Formation	Laramie Formation	
	Fox Hills Sandstone	Fox Hills Sandstone	
	Richard Sandstone Member	Pierre Shale	
	Terry Sandstone Member	Pierre Shale	<b>Niobrara Formation and Codell Sandstone SAU</b> C50390104 Seal: Pierre Shale Reservoir: Codell Sandstone Member of the Carlile Shale, Fort Hays Limestone and Smoky Hill Shale Members of the Niobrara Formation
	Hygiene Sandstone Member	Pierre Shale	
	Smoky Hill Shale Member	Niobrara Formation	
	Fort Hays Limestone Member	Niobrara Formation	
	Codell Sandstone Member	Carlile Sandstone Member	<b>Greenhorn Limestone SAU</b> C50390103 Seal: Carlile Shale Reservoir: Greenhorn Limestone
	Carlile Shale	Carlile Shale	
	Greenhorn Limestone	Greenhorn Limestone	<b>Muddy Sandstone SAU</b> C50390102 Seal: Mowry and Graneros Shales Reservoir: Muddy ("J") Sandstone and "D" sandstone
	Graneros Shale	Graneros Shale	
Lower Cretaceous	Mowry Shale	Mowry Shale equivalent	<b>Plainview and Lytle Formations SAU</b> C50390101 Seal: Skull Creek Shale Reservoir: Lytle Formation, "Lakota" of drillers, "Dakota" of drillers, Inyan Kara Group, Plainview Formation, and Plainview Sandstone Member of the South Platte Formation
	South Platte Fm. (South members, South Platte Formation)	Muddy ("J") Sandstone	
	Skull Creek Shale	Skull Creek Shale	
	Plainview Sandstone	Plainview Formation	
	Lytle Formation	Lytle Formation	
Jurassic	Morrison Formation	Morrison Formation	
	Ralston Creek Formation	Older Jurassic rocks may be present	
	Sundance Formation		
Triassic	Jelm Formation	Jelm Formation	
Permian	Lykins Formation	Lykins Formation	
	Lyons Sandstone	Lyons Sandstone	
	Owl Canyon Formation	Owl Canyon Formation	
	Ingleside Formation	Ingleside Formation	
Pennsylvanian	Fountain Formation	Fountain Formation	
Mississippian		Leadville Limestone	
Devonian		Devonian rocks	
Silurian			
Ordovician	Fremont Dolomite	Manitou Formation	
	Harding Sandstone		
	Manitou Formation		
Cambrian	Sawatch Quartzite	Reagan/Lamotte Sandstone	

The above stratigraphic column illustrates the binding formations above and below the Lyons formation as well as the stratigraphic location of the hydrocarbon zones in the DJ Basin. This stratigraphic column is representative of the geologic location of the Wattenberg Disposal within the DJ Basin. A cross-section for the Lyons formation cannot be assembled due to the lack of geologic and log data at the depth of the Lyons formation in the area near the Wattenberg Disposal well.

**Part II: Proposed Formation Testing Program**

Type of Test	Frequency
Internal (Part I) MIT may be demonstrated with a pressure test using liquid or gas	Every five (5) years after the last successful demonstration of mechanical integrity
External (Part II) MIT shall be demonstrated by Option 1: A temperature log or noise survey or Option 2: An alternative temperature log and supplemental Radioactive Tracer Survey	Every five (5) years after the last demonstration of mechanical integrity If a temperature log (Option 1) only is performed then use the EPA testing Guideline – “Temperature Logging for Mechanical Integrity” Note: All tests must be performed using the maximum allowable injection pressure
Fall Off Test and Calibration and Pore Pressure Data	Annually after the last successful demonstration of pressure fall of. Shall be performed for the purpose of monitoring pressure buildup in the injection in order to detect any significant loss of fluids due to fracturing in the injection and/or confining zone, and to aid in determining the lateral extent of the injection plume
Cement Bond Logs	Performed after any work that involves any remedial cementing of the casing

# Form 7520-6 Attachment C

## Part I: Well Schematic Diagram

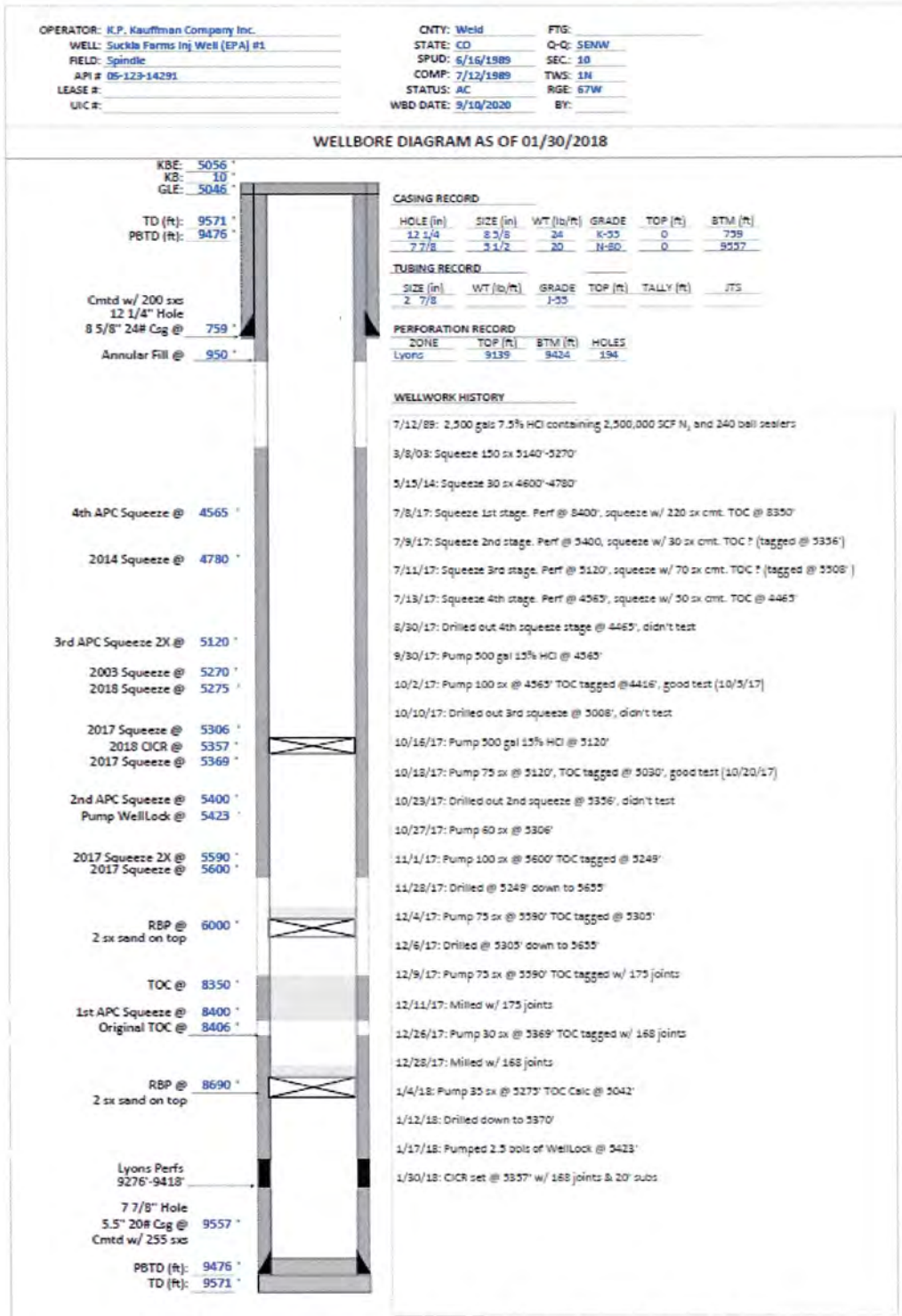


Figure 1: Wellbore Diagram Before KPK Began Operations in the Fall of 2020.



**Table #1: Current Wellbore Construction**

Hole Size (in)	Casing Size (in)	WT (#/ft)	Grade	Setting Depth (ft)	Cement Top (ft)
12 1/4	8 5/8	24	K-55	759	0
7 7/8	5 1/5	20	N-80	9557	8406
*Squeeze for APC				8400	8350
*Multiple Squeeze Jobs				5600	4465
*Annular Fill				950	0

**Part II: Well Construction or Conversion Procedures****Table #2: Proposed Wellbore Construction**

Hole Size (in)	Casing Size (in)	WT (#/ft)	Grade	Setting Depth (ft)	Cement Top (ft)
12 1/4	8 5/8	24	K-55	759	0
7 7/8	5 1/2	20	N-80	9557	8406
4 2/3	3 1/2	9.3	J-55	9200	4000
*Squeeze for APC				8400	8350
*Multiple Squeeze Jobs				5600	4465
*Annular Fill				950	0

The procedure for the proposed work is as follows:

1. MIRU KPK WO Rig #12
2. TIH w/ tubing to re-tag sand
3. Wash down sand to 9205'
4. TIH w/ cement shoe and 9200' 3.5" 9.3# liner.
5. RU cement. Cement liner from 9200' to approximately 4000' with 261 sx and displace with 2% KCl, bump plug, shut down for 24 hrs.
6. RU wireline to run a CBL
7. TIH w/ bit and tubing
8. Circulate sand out of hole to PBTD of 9476'
9. TOH and LD bit
10. Pick up 3.5" injection packer
11. TIH w/ packer, circulate packer fluid, and set packer at 9175'
12. Set up to run MIT (assume MIT passes)
13. RU pump truck and pump 2500 gal 15% HCl w/ diverter
14. Swab back acid and prepare to run pressure fall off test and temperature survey
15. RDMO Rig #12
16. Wait on further orders from EPA
17. Assuming successful tests and EPA approval, the well will be brought back online to resume disposal operations

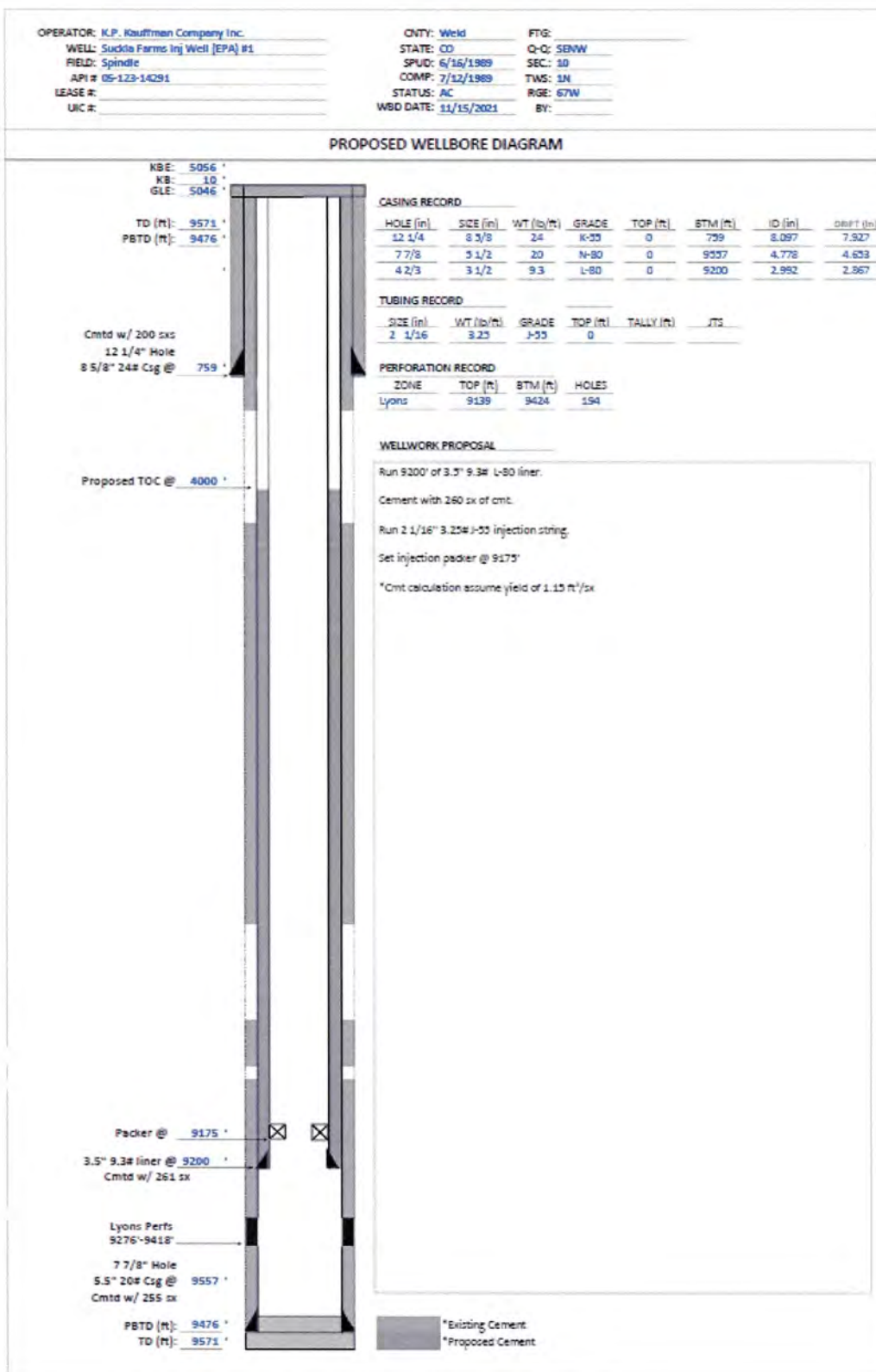


Figure 3: Proposed Wellbore Diagram.

**Maximum Allowable Injection Pressure (MAIP)** as measured at the surface shall not exceed the pressure(s) listed below:

Well Name: Suckla Farms #1 Injection Well

Maximum Allowed Injection Pressure: 3700 psi (UIC Compliance/Enforcement Database)

Any increase in pressure that exceeds 3695 psi shall result in an immediate shut down of the injection pumps.

Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure cause the movement of injected or formation fluids into a USDW.

**Annulus Pressure:** The annulus pressure shall be maintained at a positive pressure between one hundred (100) and two hundred (200) psi gauge as measured at the wellhead.

Any operation outside of this range shall result in an immediate shut down of the injection pumps. When adjusting the annulus fluid pressure, the Permittee shall use the target value of 150 psi.

If this pressure cannot be maintained between 100 psi and 200 psi, the Permittee shall follow the procedures listed in *Ground Water Section Guidance No. 35* "Procedures to follow when excessive annular pressure is observed on a well."

**Maximum Injection Volume:** Cumulative injection volume of oil field water, plus Class I nonhazardous waste fluid will be limited to 8,300,000 barrels over the life of the well unless EPA decides to extend the limits of the injection zone or to terminate the permit.

**Maximum Injection Rate:** The injection rate is not limited.

## Form 7520-6 Attachment D

### Injection Operation and Monitoring Program

**Table #1: Injection Zone Pressures**

Formation Name	Depth Used to Calculate	Fracture Gradient (psi/ft)	Specific Gravity	MAIP (psig)
Lyons Formation	9276 ft	0.8415	1.022	3700

An MAIP of 3700 psig was the highest value observed during a 1993 step rate test with no breaking point (formation fracture pressure) observed. Therefore, no formation breakdown of the Lyons injection zone occurred up to the termination of the test at a surface injection pressure of 3700 psig and at an injection rate of 8.0 barrels of water per minute.

#### Approved Injection Fluid

The approved injection fluid is limited to produced oil field waters, as authorized under the provisions of the previously issued Class II permit, plus nonhazardous industrial waste fluids, as provided for in this Class I permit.

**Table #2: Injected Fluid Characteristics**

<i>SUSSEX FORMATION SOURCE WATER</i>	<i>SPECIFIC GRAVITY</i>	<i>TDS, mg/l</i>
<i>Spindle Field produced water</i>	<i>1.02</i>	<i>13,800</i>
<i>produced water</i>	<i>1.017</i>	<i>11,065</i>
<i>Suckla Brown Unit</i>	<i>1.022</i>	<i>12,860</i>

#### Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs. The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit. Table #1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)

fg = fracture gradient (from submitted data or tests)

sg = specific gravity (of injected fluid)

d = depth to top of injection zone (or top perforation)

- $f_g = 0.8415$  psi/ft
- $sg = 1.022$
- $d = 9276$  ft (top perforations in the Lyons Sandstone injection zone)
- $FP = 3700$  psig

A Step Rate Test was performed on July 9, 1993. This test was performed on the Lyons injection interval between the depths of 9,276.ft - 9,418.ft in the Suck/a Farms #1 well. The operator will need to perform additional tests, including a new Step Rate Test should they request the installation of new perforations or to request an increase in pressure (MAIP). Using the calculation above, the fracture pressure was determined to be 3700 psig.

### **Injection Volume Limitation**

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

The injection volume is recorded in Appendix E of the Permit. Cumulative injection volume of oil field water, plus nonhazardous waste fluid will be limited to 8,300,000 barrels over the life of the well unless EPA decides to extend the limits of the injection zone or to terminate the permit. This volume was calculated using the formula shown below, which indicates the amount of fluid required to fill up the portion of the reservoir within a 1/4 mile radius around the injection well.

$$V = (\pi r^2 h n) / 5.615$$

Where

$\pi = 3.14159265$

$r = 1320$  ft or 1/4 mile = radial distance

$h = 142$ ft =height of injection zone available for fill up (ft)

$n = 0.06$  =porosity of injection zone (decimal percent)

5.615 = conversion factor (barrels andft<sup>3</sup>)

$V = 8,300,000$  barrels = maximum cumulative volume (bbl)

### **Mechanical Integrity (40 CFR 146.8)**

An injection well has mechanical integrity if:

1. There is no significant leak in the casing, tubing, or packer (Part I); and
2. There is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

The applicant is required to perform a Part I and Part II MIT as follows:

- Part I, Shall be performed at least every five (5) years after the last successful demonstration of Mechanical Integrity.
- Part II, Shall be performed at least every five (5) years after the last successful demonstration of Mechanical Integrity. Federal regulation 40 CFR 146. 8(c) 1 requires the absence of significant fluid be determined with either a temperature or noise log. Therefore, a temperature log with a supplemental radioactive tracer survey may be used to perform Part II (External) Mechanical Integrity Testing.

The applicant shall perform tests as follows:

- With a Temperature Logs or a noise log or
  - With a Temperature Log and supplemental Radioactive Tracer Survey
- Pressure Fall Off Tests with pore pressure data shall be performed annually following the last successful Pressure Fall Off Test as approved/accepted by the EPA Region 8 office.

### **Injection Well Monitoring Program**

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA quarterly as part of the Quarterly Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, injection flow rate and cumulative fluid volume, and the maximum and average value for each must be determined for each month. This information is required to be reported quarterly as part of the Quarterly Report to the Director.

All industrial waste fluids delivered to the facility will be sampled for fluid analysis prior to delivery, or prior to being transferred to an on-site 500 barrel storage tanks. These fluid samples shall be analyzed for chemical, physical, radiological, and biological constituents, including pH and conductivity. If the analyses of several loads from the same source indicate little or no change, the Director may elect to waive the requirement that each load be sampled. However, one load of industrial waste coming from the same source (where the process is not likely to change) must be tested each month prior to being transferred to on-site tanks.

A flow meter will measure the quantity of fluids pumped from the storage tanks to the injection system. The commingled fluids will be sampled/or analysis at random, but not less than once every three months. This final analysis shall include a determination of total dissolved solids, pH, specific gravity, specific conductivity, major cations and anions, oil and grease, and total organic carbon.

The permittee requires that the average, maximum, and minimum monthly values of injection pressure, flow rate and volume, and annular pressure be reported quarterly, along with the data from fluid analyses. In addition to routine quarterly reporting, the permittee is required to report the results of any mechanical integrity test, well workover, logging, or testing of the well or

injection zone. These reports are due within sixty (60) days of the completion of the activity, or at the time of the next scheduled quarterly report, whichever is sooner.

Seismicity data has been included to ensure that EPA is informed of any seismic occurrences in the area. Pore pressure data will be collected to determine if pressure has risen in the proposed location. This information will be used to determine what next steps may be required as a result of recent seismic activities.

The monitoring devices shall continuously monitor: (1) injection pressure; (2) casing head pressure of the tubing/casing annular space; and (3) flow rate and volume. The tubing/casing annulus is to be filled with fluid and maintained between a positive pressure of 100 - 200 psig. This may be achieved through the use of an above-ground fluid reservoir with a gas cap of nitrogen to maintain the positive pressure. A continuous recording of injection volume can be accomplished by use of a cumulative volume totalizer. The permittee shall provide and maintain in good operating condition: a 1/2 inch fitting with a cut-off valve at the wellhead on the tubing, and a similar fitting and cut-off valve for the casing/tubing annulus. These valves shall be positioned to allow the attachment of pressure gauges certified for ninety-five (95) percent accuracy, or better, throughout the range of permitted operation, in order to monitor the injection and annulus fluid pressures. A flow meter shall be installed near the wellhead to measure cumulative volumes of injected fluid. These gauges will serve as a check against the readings recorded by the continuous monitoring devices. EPA is further requiring that a sampling tap exist on the line to the disposal well.

## Site Diagram

Image #1: Wattenberg Disposal Facility Diagram



## Form 7520-6 Attachment E

### Plugging and Abandonment Plan

The Plugging and Abandonment Plan incorporated into this Permit is binding on the Permittee. After receiving approval from the Colorado Oil and Gas Conservation Commission, and notifying the appropriate Regional EPA office, the permitted injection well will be plugged and abandoned in accordance with the following Plugging and Abandonment Plan.

Note: Cemented areas using balanced plugs shall be tagged. Class C or similar type cement shall be used to Plug and Abandon the Suckla Farms #1 Injection Well. Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 lb/gal shall be used during plugging operations, and shall remain between plugs in the well after cement plug placement.

1. Run a Part I (Internal) Mechanical Integrity Test to evaluate casing integrity. If casing has integrity, prior to plugging and abandoning the Suckla Farms #1 disposal well, the tubing and packer will be removed from the well bore.
2. Plug #1: Isolation of the Injection Zone and Upper Confining Zone. Set CICR @ 9150 ft. Sting into retainer and pump 326 ft from 9476' to 9150'. Sting out of CICR and pump 50 ft on top using Class B type II neat cement or an equivalent Class G cement. Wait sufficient time for plug to set and tag plug with tubing string.
3. Plug #2: Isolation of the Pierre Shale Formation. Set a 200 ft plug, using Class G, or equivalent type cement, from 7100 ft to 7300 ft inside the 3 1/2 inch casing.
4. Plug #3: Isolation of known USDWs and the Surface Casing Shoe. Perforate at 810 ft and squeeze 160 ft of cement between the 3 1/2 inch liner and the 5 1/2 inch casing as well as inside the 3 1/2 inch liner.
5. Plug #4: Isolation of the Surface. Set a sufficient Class "G" cement plug to fill the 3 1/2 inch liner from the surface to a minimum depth of 100 feet. The annular space between the 5 1/2 inch casing and the 3 1/2 inch liner must also be filled with cement.
6. After the wellbore is plugged the Permit requires cutting off the 8 5/8 inch casing 1 to 3 feet below ground surface. A steel cap dry hole marker is required to be welded on the 8 5/8 inch casing. The surface must then be restored to landowner and/or County requirements.

### Plugging and Abandonment Cost Estimate

Rig Costs	\$22,000
Supervision Costs	\$6,500
Materials Trucking Costs	\$4,000
Water Hauling and Disposal Costs	\$3,000
Cement Costs	\$15,000
Site Reclamation Costs	\$10,000
Contingency	\$6,550
Total P&A Costs	\$72,050

**Form 7520-6 Attachment F**

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

*A demonstration of Financial Responsibility in the amount of \$84,852 has been provided. The Director may revise the amount required, and may require the permittee to obtain and provide updated estimates of costs for plugging the well according to the approved Plugging and Abandonment Plan.*

## Form 7520-6 Attachment G

### Site Security

#### *Signage*

Waterproof sign(s) shall be maintained and readily visible at the entrance from public roads leading to the commercial disposal well. The sign(s) shall indicate the property is private, no trespassing is allowed, and shall include the name of the Permittee and emergency contact phone number.

#### *Gates and Fences*

The perimeter of the site shall be fenced with a minimum 6-foot high metal pipe fence with woven wire between the posts or an equivalent chain-linked fence. All gates and other entry points shall be locked when the facility is unattended. Only authorized personnel shall have access to the site and ability to open the gates.

#### *Surveillance*

The site shall be monitored by 24 hour camera surveillance (i.e. recording cameras). If an electronic system is used to secure the facility or if fluids to be disposed in the well are transported to the facility by pipe, an automatic shut-off or alarm system is available to ensure that disposal operations cease if a well mechanical failure or downhole problem occurs. If an electronic system is not used to secure the facility, fluids shall be received for placement in a commercial disposal well only when there is an attendant on duty if fluids are hauled in by truck. All sites not protected by an electronic system shall be secured by a locked gate when an attendant is not on duty.

#### *Tamper Proof Locks*

The Permittee shall provide tamper-proof seals for the master valve on the well; and install locking caps on all valves and connections on holding tanks, unloading racks, and headers. Leak containment. A means for containing leaks shall be provided at all pumps and connections.

**Form 7520-6 Attachment H**

The total dissolved solids of the Lyons formation was determined to be 33,000 mg/liter and an aquifer exemption is not needed.

**Form 7520-6 Attachment I**

There are no other existing EPA permits for this disposal well and facility.

**Form 7520-6 Attachment J**

K.P. Kauffman Company, Inc., ("KPK") is an independent oil and gas production, drilling, well service and transportation company engaged in the exploration, development, acquisition, operation and well service of oil and gas properties in the Rocky Mountain States, Denver-Julesburg Basin, North Park Basin, and Permian Basin. KPK is the contract operator for the Wattenberg Disposal well and facility. Wattenberg Disposal L.L.C. is a company that owns the Wattenberg Disposal commercial facility that disposes of third party waste as well as KPK's internal salt water waste.